SB 437

Support the following (could tend to reduce rates or control costs):

1. p. 4 lines 1-27, pg. 5 lines 1-7: Self –implemented rates repealed; refund problems mitigated.

2. p. 26 commencing at line 16: Statewide integrated resources plan required.

3. p. 39 line 27: Projected rate impact of IRP Plan required to be considered.

4. p. 41 line 11: Performance based regulation studied with collaboration of representatives of each customer class.

5. p. 42 lines 15 & 16: Performance based rate making to consider profit sharing provision to spread proficiency gains among customers and utility shareholders.

Oppose as written the following (likely increase utility revenues or raise rates):

1. p. 3 line 13: Still allows utilities to use projected cost in developing requested rates and charges. Utilities should be required to use a historical test year with adjustments for only known and reasonable changes.

2. p. 6 line 24: Rate cases must be decided in ten (10) months, not twelve (12) or request is automatically approved. Only if self-implementation is eliminated and should be an option for commission to extend to 12 months if necessary due to the complexity of the case.

3. p. 11 lines 1-10: Allows revenue decoupling for electric and gas utilities and requires the Commission give deference to the utilities' proposed decoupling plans. With the ability to file rate cases every 12 months, revenue decoupling is currently provided to the utilities via the rate case regulatory process. The current rate case process creates an environment that allows the utilities to earn their authorized rate of return while also protecting all customers from line item approvals or fractured rate-making that could result in excessive earnings by the utilities. While initially created to encourage energy efficiency, separate revenue decoupling mechanisms for natural gas have increased consumer rates, even when the utilities are earning more than their authorized rate of return. Any adjustment to the utilities' rates should only take place after complete PSC review in a rate case. Legislation should never limit the commission's ability to determine the merits of a program by requiring the commission to give deference to the utilities proposal.

4. p. 31 lines 3-5: A utility is not required to accept any proposals submitted in response to its RFP from the IRP, thus making the RFP unlikely to attract other proposals. In addition to a robust Integrated Resource Planning Process (IRP) which will identify the existing generation resources and the timing/need for new resources, enormous consumer cost savings can be achieved if electric utilities are required to utilize a competitive bid/supply

planning process like other industries do. If it is determined through the IRP that new generation capacity is required, this competitive bid supply planning process must not favor or give advantage to native utility companies. Non-utility companies should not be limited to construction only or partial ownership. A large portion of cost savings can come from the efficient operation and maintenance of the generation plant.

5. p. 34 lines 23 & 24: As written intervention can only be by parties "approved" by the Commission rather than "interested" parties which should have a "right" to intervene.

6. p. 35 lines 7-15: The Commission may authorize a rate of return on PPAs, and PPAs that are included in an approved IRP are automatically considered reasonable for cost recovery purposes even if a mistake; thus shifting risks to customers and utility keeps high ROE as though bear the risk. However if the PPA (including the cost of an authorized rate of return to the utility) is selected as the best option through the IRP and competitive bid process than this would be acceptable.

7. p. 36 lines 20-27 and p. 27 lines 1-3: Attempts to limit the manner and scope of judicial review of an Integrated Resources Plan by the Court of Appeals.

8. p. 37 lines 4-27 and p. 38 lines 1-27: Effectively shifts all risks of mistaken plan on to customers without any off-set in ROE of utility.

9. p. 40 line 17: Only an electric utility can seek amendments to an approved IRP. Other interested persons should be able to seek amendments.

10. p. 41 lines 1-7: Only certain government entities can request a plan review, not customers. Customers should be able to petition for a plan review.

11. p. 42 lines 4-8: Seeks to increase time between rate cases to provide utilities with more opportunity to retain cost saving without having to reduce rates. Agree that performance based regulation should be studied. However there is no need for legislation to specify what should be included in a performance based system. What should be included needs to be part of the study and recommendation.

12. p. 46 lines 6-27 and p. 47 lines 1-5: **Regulates customers** not utilities and requires customers give certain notices in order to stay on choice. At a minimum ten percent retail choice needs to be maintained as is.

13. p. 47 lines 11-19: Even for customers who elect to stay on choice attempts to regulate how much they can expand their use of choice by limiting the expanded use of choice to facilities that are "similar in nature" and where the customer owns more than fifty percent of the new facility. If a customer is on retail choice there should not be any limits on what existing facilities or new facilities that customer can serve using retail choice.

14. p. 47 lines 20-27: **Penalizes customers** who return to service by requiring that they are no longer eligible to ever receive competitive service from an AES. At a minimum ten percent retail choice needs to be maintained as is.

15. p. 48 lines 2-7: **<u>Requires customers</u>** returning to utility service provide three (3) years advance written notice. Existing return to service provisions are adequate. However if the utility can demonstrate that existing full service customers will incur cost associated with the returning customer than the returning customer should assume those cost.

16. p. 48 lines 7-8: Provides that a notice of intent to return to standard service is irrevocable. Utility must be required to identify any cost that the returning customer would incur within 30 days of the notice to return to full service by the customer. Returning customer should then have 30 days from the date of such cost notice to withdrawal their notice of intent to return to full service.

17. p. 48 lines 9 & 10: Allows the utility to **<u>legally discriminate</u>** against customers by waving the notice requirements for some customers and not for others. Existing return to service provisions are adequate.

18. p. 48 lines 16-21: Provides that if a returning customer did not provide three years notice and such return causes additional cost or impairs reliability, unspecified penalties can be assessed to the returning customer in addition to the incremental costs. Any and all additional cost to the returning customer needs to be identified prior to the customer making their final commitment to return.

19. p. 48 lines 22-27 and p. 49 lines 1-10: Provides that a customer on the waiting list must take the next supply available within seven (7) days or that customer is removed from the list and is not eligible again for customer choice service. Seven days is ok for a customer to provide notice that they accept the open position. However 7 days is not enough time to finalize all agreements with the choice supplier and begin taking retail choice service.

20. p. 49 lines 2-22: Requires that an AES file all of its electric supply contracts with the Commission. Presents serious customer and supplier confidentiality issues with no easy way to really protect the information.

21. p. 50 lines 5-13: Requires an AES demonstrate dedicated firm physical electric generating capacity to serve choice customers for three (3) years. At most this requirement should only be tied to length of contract with customer.

22. p. 50 lines 14-27 and p. 51 lines 1-4: Requires AES demonstrate five (5) years capacity if MISO forecasts a shortfall two years out. What does "capacity shortfall" mean? We have seen the MISO assessment be way off and substantially revised from year to year.

23. p. 51 lines 5-12: Limits the Commission in considering whether adequate capacity has been demonstrated to **<u>only</u>** capacity physically located in Michigan.

24. p. 51 lines 13-16: Limits the demonstrable capacity from power purchase contracts to only those that are **<u>pre-paid</u>**. Why is this more onerous than the requirements of the investor owned utilities? IOU's do not pre-pay for PPAs.

25. p. 51 lines 18-23: Limits the demonstrable capacity to no more than five (5) percent coming from market auction purchases. The MISO auction was specifically setup as a

market tool for the efficient purchase of capacity. This provision will only increase cost for retail choice customers.

26. p. 52 line 20-23: Requires the Commission establish a planning reserve margin for customers served by AES, and effectively establishes a fifteen percent reserve margin for AES. Again, why is this more onerous than the requirements of the investor owned utilities?

27. p. 53 lines 1-5: Prohibits the Commission from considering demand response measures in considering whether the reserve margin has been met unless it can find that the demand response measures are as reliable as firm physical generating capacity.

28. p. 53 lines 13-15: **Effectively relieves the electric utility from compliance with the Code of Conduct** and makes possible for the electric utilities unregulated affiliate to compete unfairly against AESs and cross subsidize costs from utility operations.

29. p. 53 line 20-26: Authorizes an electric utility to create new "value added programs and services" without regard to compliance with the Code of Conduct, thus effectively authorizing cross-subsidization from the monopoly services.

30. p. 56 lines 23-27 and p. 57 lines 1-5: Repeals long standing regulations which require revenues from non-utilities services be included in setting rates (which historically recognized that you really could not control utilities trying to cross subsidize businesses) and specifically authorizes utilities to retain profits generated from unregulated business ventures without regard to the Code of Conduct.

31. p. 74 lines 26 & 27: Allows an electric utility to shut off a customer for non-payment of energy efficiency charges.

32. p. 75 lines 12-14: Allows the electric utility to shut off a customer that has not paid the per meter charge for energy efficiency and optimization programs.

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Oppose the following (likely increase utility revenues or raise rates):

1. p. 46, 48, 51, etc.: Costs of the programs can be volumetric charges. For many industrial this could be a substantial increase. Any energy efficiency charge must be a per meter charge.

2. p. 36: Financial incentive INCREASED from 15% to 20%. EE, Waste Reduction and DR should be treated as generation resources and be part of the IRP and competitive bidding process. If these truly are the lowest cost resources than they will be selected through this process and the utility should be allowed to earn a return on their investment in these programs.

3. p. 50: Allows natural gas utility to implement a revenue decoupling mechanism. With the ability to file rate cases every 12 months, revenue decoupling is currently provided to the utilities via the rate case regulatory process. The current rate case process creates an environment that allows the utilities to earn their guaranteed rate of return while also protecting all customers from line item approvals or fractured rate-making that could result in excessive earnings by the utilities. While initially created to encourage energy efficiency, separate revenue decoupling mechanisms for natural gas have increased consumer rates, even when the utilities are earning more than their authorized rate of return. Any adjustment to the utilities' rates should only take place after complete PSC review in a rate case.

4. p. 54, Section 93: Manufacturing customers have requested that the self-directed provisions be simplified, eliminate some of the red-tape and the penalty provisions for not meeting targets, and let manufacturing customers spend their own money on their own programs, rather than be charged a surcharge and then try to get their own money back in a grant. NONE of these requests is reflected in SB 438. In fact, nothing really has changed except the name from energy optimization to waste reduction.

5. p. 68, Section 173: Originally in Act 295 this was a small net metering program for very small load. In SB 438 it has become a comprehensive distributed generation program designed to restrict self-generation and protect the monopoly position of the incumbent utilities. The total amount of load eligible is capped at 10% of the average peak over the last 5 years, and of the 10%, only 2.5% can come from eligible generators producing more than 150 kw. I do not know how much current self-generation or distributed generation is out there already, but this is clearly designed to restrict it. The following amendment needs added to protect industrial manufacturing customers' right to build, own and operate cogeneration:

   Sec. 173.
   (8) Notwithstanding any other provision of this act, nothing in this act shall in any way limit or restrict an industrial customer's ability to build, own, operate or have a third party build, own and operate one or more self-generation or cogeneration facilities. As used in this section, "cogeneration facilities" means equipment used to produce electric

energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy.

Also, the PSC can allow the utilities to require inverters owned and controlled by the utilities. Finally the pricing is proposed to change so that the customer has to pay the full retail rate for all electricity and then gets a bill credit back for the value of the avoided energy cost, which will be the day ahead wholesale energy rate at MISO.